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Article

Life Cycle GHG Perspective on U.S. Natural Gas Delivery Pathways

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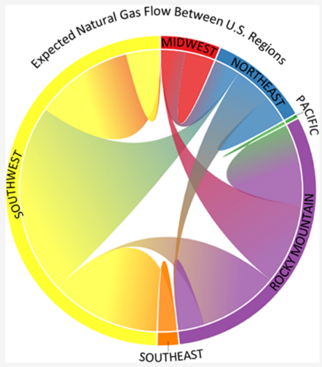
ABSTRACT: Recent emission measurement campaigns have improved our understanding of the total greenhouse gas (GHG) emissions across the natural gas supply chain, the individual components that contribute to these emissions, and how these emissions vary geographically. However, our current understanding of natural gas supply chain emissions does not account for the linkages between specific production basins and consumers. This work provides a detailed life cycle perspective on how GHG emissions vary according to where natural gas is produced and where it is delivered. This is accomplished by disaggregating transmission and distribution infrastructure into six regions, balancing natural gas supply and demand locations to infer the likely pathways between production and delivery, and incorporating new data on distribution meters. The average transmission distance for U.S. natural gas is 815 km but ranges from 45 to 3000 km across estimated production-to-delivery pairings. In terms of 100-year global warming potentials, the delivery of one megajoule (MJ) of natural gas to the Pacific region has the highest mean life cycle GHG emissions (13.0 g CO_2e/MJ) and the delivery of natural gas to the Northeast U.S. has the lowest mean life cycle GHG emissions (8.1 g CO_2e/MJ). The cradle-to-delivery scenarios developed in this work show that a national average does not adequately represent the upstream GHG emission intensity for natural gas from a specific basin or delivered to a specific consumer.



KEYWORDS: *natural gas value chain, natural gas transmission, natural gas distribution, greenhouse gas, global warming potential*

■ INTRODUCTION

Advancements in unconventional extraction technologies have brought a rapid increase in U.S. natural gas production, enabling growth in domestic natural gas-fired power generation and liquefied natural gas (LNG) exports. From 2010 to 2020, the volume of natural gas produced in the U.S. grew by 62%, from 22.4 to 36.2 trillion cubic feet (Tcf).[1] With this growth comes questions about the sustainability of natural gas and, more specifically, the greenhouse gas (GHG) emissions from the natural gas supply chain. In 2018, the carbon dioxide (CO_2) and methane (CH_4) emissions from the U.S. natural gas supply chain totaled 237 million tonnes of carbon dioxide equivalents (CO_2e).[2] For CH_4 alone, natural gas systems accounted for 26% of the U.S. Environmental Protection Agency's (EPA) inventory of CH_4 emissions in 2018. Understanding the ways in which CO_2 and CH_4 are emitted from the supply chain is necessary for the development of effective strategies for GHG emission reductions.

Recent emission measurement campaigns have improved our understanding of natural gas CH_4 emissions.[3−6] The data from these measurement campaigns have enabled the synthesis of total supply chain CH_4 emission rates and have provided insight into the extreme variability in CH_4 emissions.[7−15] Often, this variability takes the form of long-tailed probability distribution functions that imply that a small number of emitters contribute a large share to total supply chain emissions. These long-tailed probability distribution functions are an obstacle to predicting the emission intensity for a given facility or group of facilities.[16−21] Reported data have also given us insight into supply chain emissions, including component-level contributions and regional variability. For instance, EPA's Greenhouse Gas Reporting Program (GHGRP)[22] provides transparent self-reported data on the counts and operating hours for individual components and has allowed us to stratify GHG emissions from specific production basins, midstream processing and transmission facilities, and local distribution companies.[23] Similarly, in past work, we regionalized the natural gas supply chain using combinations of extraction technologies and production basins ("technobasins") to show how life cycle emissions vary based on how and where natural gas is produced. This technobasin approach shows that life cycle CH_4 emission rates for U.S. natural gas sources range from 0.5% (offshore platforms in the Gulf of Mexico and Alaska) to 3.8% (San Juan Conventional production in the Four Corners region).[23,24] Other analysts have also disaggregated the geographic characteristics of natural gas GHG emissions. As recommended by a consensus report on quantifying CH_4 emissions, geographically resolved emission inventories are necessary to identify top-priority emission reduction opportunities.[25] Maasakkers et al. developed a U.S.

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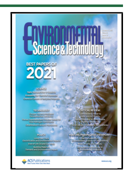

gridded inventory that allows CH_4 emission comparisons among sectors at a spatial resolution of 10 square kilometers.[26] Their gridded inventory shows that production in Pennsylvania, Texas, and the Four Corners region are emission hotspots for the natural gas sector.

The above studies have furthered our understanding of key CH_4 emission contributors and geographic variability across the natural gas supply chain; however, they do not provide information on the linkages between specific production and consumption locations. The objective of this work is to provide a more detailed life cycle perspective on how GHG emissions vary according to where natural gas is produced and where it is delivered. We accomplish this by disaggregating transmission and distribution infrastructure into six regions and balancing natural gas supply and demand locations to infer the likely pathways between production and delivery. This work is possible because of an approach that we developed to link specific production basins to specific consumption regions and emission data for industrial and commercial meters collected by a recent measurement study by the Gas Technology Institute (GTI).[27]

This work is novel because it models supply chain scenarios where emissions depend on where natural gas is produced and consumed. It does so by adding more details to the transmission and distribution stages of the natural gas supply chain. For natural gas transmission, existing work has characterized the emission variability for natural gas transmission compressor stations, but upon incorporation into emission inventories or life cycle models, these data are aggregated to a national level that obscures geographic variability.[15] For natural gas distribution, past work has identified cast iron mains as a key differentiator in methane emissions from local distribution systems.[24] In this work, we build upon such work by incorporating new emission factors for commercial and industrial meters and show how these emissions vary for different delivery regions. Existing work has also developed approaches for tracking natural gas through district power and heating systems;[28] here, we focus on midstream and local distribution systems to track natural gas from production through end use and, in turn, develop specific scenarios for life cycle GHG emissions.

There is one study that partially coincides with our work. Burns and Grubert studied pipeline connections and capacities to attribute a unique production methane emission intensity for natural gas consumed in each state (they do not account for emissions downstream from the production stage).[29] Burns and Grubert found that the production stage methane emission intensity ranges from 0.9 to 3.6%. Our work presents an alternate approach to estimating producer-to-consumer pipeline pathways. Additionally, our work includes all GHG emissions (CO_2, CH_4, and N_2O) from all stages of the supply chain and accounts for variability in midstream transport technologies and local distribution systems.

A life cycle perspective with supply chain connectivity is necessary for answering questions about specific natural gas production and consumption scenarios. This type of connectivity is not provided by emission inventories, which do not consider upstream-to-downstream relationships and do not attribute emissions to a unit of production. Similarly, this type of connectivity is not provided by sector-level Life Cycle Assessments (LCAs), which aggregate supply chains in a way that prevents differentiation between high- and low-emission-intensity scenarios. The level of detail and connectivity in this work is a useful tool for companies who need accurate life cycle metrics for their products or industry groups and policy makers who want to enact targeted emission mitigation strategies. The ability to differentiate supply chain scenarios is increasingly relevant for the natural gas sector because U.S. liquefied natural gas (LNG) exports are a growing share of the global energy portfolio and import markets are under pressure to compare the GHG intensities of LNG and competing energy sources.[30] Not all natural gas pathways are the same, which means that aggregated, sector-level emission profiles are misleading when applied to a single consumer.

METHODS

This work uses the National Energy Technology Laboratory's (NETL) life cycle natural gas model to calculate the cradle-through-delivery GHG emissions from the natural gas supply chain (hereafter referred to as the "life cycle model"). The life cycle model uses a parameterized, unit process approach. Parameterization provides a flexible way for changing the operating conditions for specific scenarios, and unit processes allow a granular level of detail where individual components are combined in an interconnected system of energy and material flows. The current version of the life cycle model has 150 specific sources of GHG emissions and holds hundreds of unique parameters for adjusting energy consumption, component counts, and emission factors. More details on the life cycle model are available in NETL's comprehensive Life Cycle Assessment (LCA) of U.S. Natural Gas. The parameterization in the model provides us with flexibility to add or enhance scenarios as new data become available. Here, we enhance the model by stratifying the transmission and storage stage to fit specific producer-to-consumer pairings, and we improve the distribution stage by incorporating new data on meters used during local distribution.

We express results in terms of GHG emissions per megajoule (MJ) of delivered natural gas (using the average higher heating value of natural gas). We use the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5) global warming potentials (GWP) for a 100-year time frame.[31] GWP is one method for converting CH_4 and nitrous oxide (N_2O) emissions from a mass basis to an equivalent mass of CO_2 and facilitates comparisons between scenarios with different mixes of CO_2, CH_4, and N_2O emissions. For CH_4, our 100-year GWP is 36, which includes the impacts from the oxidization of CH_4 to CO_2 and climate carbon feedback. We also express results in terms of CH_4 emission rate, which we define as the mass of CH_4 emissions per mass of delivered natural gas.

The boundaries for this work are from production through delivery. The natural gas supply chain has five stages: production, gathering and boosting, processing, transmission (including compression, storage, and pipelines), and distribution. In instances where natural gas is co-produced with oil, we use the energy content of the oil and natural gas streams as the basis for splitting emissions between oil and natural gas. This allocation method is applied to unit processes for well construction, well completion, well workovers, and liquids unloading. We exclude condensate storage tanks and associated gas flaring at oil wells from study boundaries because, in general, they represent activities at oil wells and should not be attributed to the natural gas supply chain. For natural gas processing facilities, we use energy-based coproduct allocation to split emissions between natural gas and natural gas liquids. We assign all of the emissions from the remaining processes at natural gas processing facilities (acid gas removal, dehydration, and compression) to natural gas.

We subdivide the data for each stage of the supply chain into six regions: Pacific, Rocky Mountain, Southwest, Midwest, Southeast, and Northeast. These regions were first defined in Gas Technology Institute's (GTI) study of distribution systems emissions;[27] for consistency, we have chosen to use the same regional definitions. Figure 1 shows a map of these six regions along with their natural gas production and consumption volumes. It shows that while some regions produce surplus natural gas, others do not produce enough natural gas and will likely use the surplus from another region to meet their consumption demand. Natural gas is consumed in a diverse set of applications, from large-scale end users to individual households. This work accounts for the delivery of natural gas to these different consumers but does not account for emissions beyond customer meters or the combustion of natural gas itself.

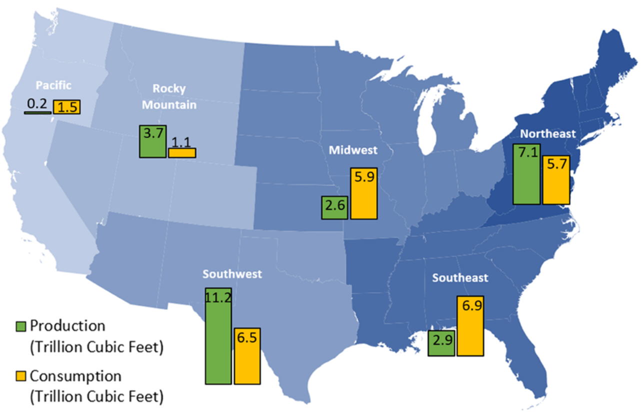

Figure 1. Six regions for U.S. natural gas transmission and distribution along with their production and consumption volumes. (This map was generated by authors in Microsoft Excel with the Bing add-in using data from the U.S. Energy Information Administration; see Table SI-18).

We use nonparametric statistical bootstrapping to characterize the way in which variability causes uncertainty. Bootstrapping is a subset of Monte Carlo simulation that generates a mean confidence interval for a statistic. The uncertainty bounds given by bootstrapping are a function of both variance and sample size. This means that the uncertainty generated by bootstrapping increases as the standard deviation increases and the number of data points decreases. The nonparametric approach samples from discrete data points as opposed to a parametric approach that samples from a continuous probability distribution function. The nonparametric approach is preferable because it avoids curve fitting error. Curve fitting is especially problematic for irregularly distributed data, like those present in natural gas systems.[16] Nonparametric statistical bootstrapping has proved valuable for analyses of natural gas systems because it is a practical way of dealing with skewed distributions and small sample sizes without introducing new error.

In this work, we developed an algorithm that simplifies the U.S. natural gas transmission network with the goal of inferring likely pathways between production and consumption. The inputs to this algorithm are the natural gas production and delivery volumes for each state and the geographic centroids of processing and delivery for each state. More details on the calculation of production and delivery volumes and our algorithm for pairing production and delivery regions are provided in the following section and are also explained in more detail in the Supporting Information.

PARAMETER DEVELOPMENT FOR TRANSMISSION AND DISTRIBUTION

Our life cycle model already comprises the parameters that account for geographic variability in natural gas production and consumption. We did not make any changes to the structure of the model, other than splitting the emissions from commercial distribution meters into two subcategories. All other data development focused on stratifying the different transmission pathways between natural gas processing facilities and the delivery regions. Prior to this exercise, the model contained a single transmission scenario that linked processing facilities and delivery regions using an average distance of 971 km and aggregated the data for all transmission storage stations into a national average. The enhanced version of the model has specialized distances and technology profiles for specific production-to-consumption pairings. The following subsections describe how we developed key parameters for the enhanced model.

Regionalized Activity and Emission Data. Our life cycle model uses emissions data from EPA's Greenhouse Gas Reporting Program (GHGRP) to develop activity factor and emission data for components that compose the U.S. natural gas supply chain.[22] For transmission and storage, these data include

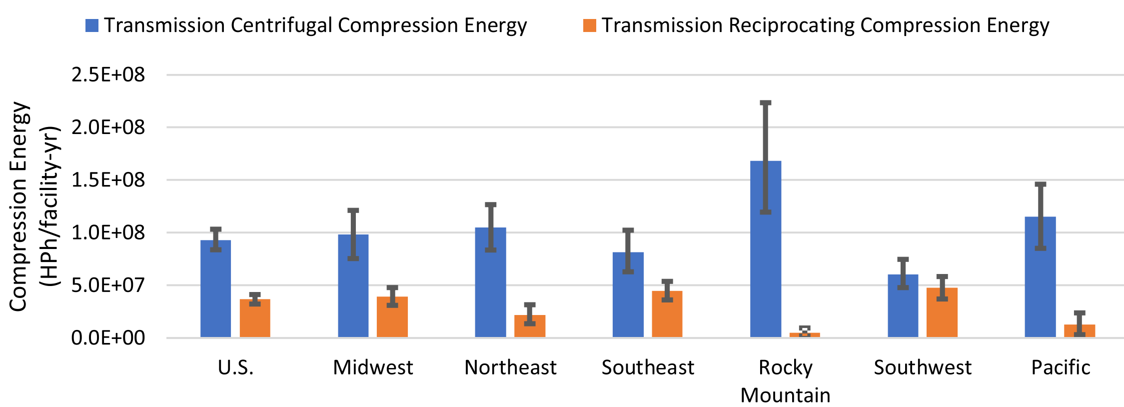

Figure 2. Compression energy for U.S. and regional natural gas transmission facilities. Most centrifugal compressors are driven by natural gas-fired turbines (with a few percent driven by electric motors) and reciprocating compressors are driven by two-stroke and four-stroke reciprocating engines. Error bars represent the 95th percentile confidence intervals around mean values.

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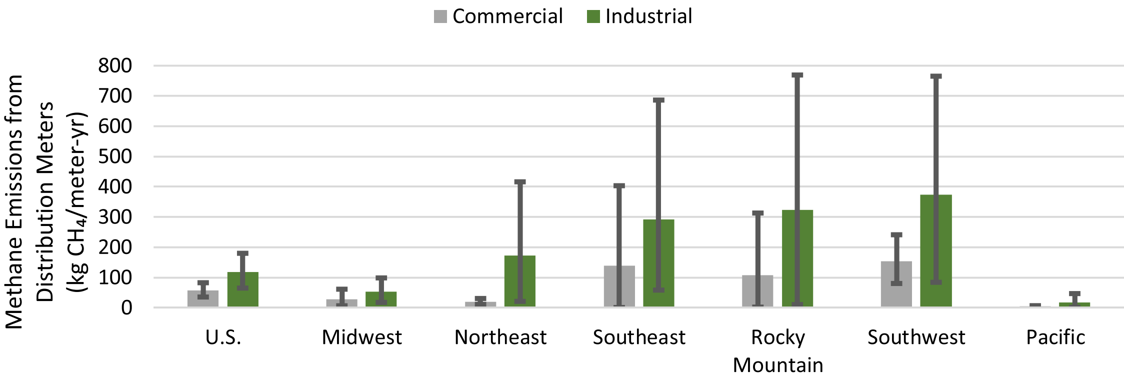

Figure 3. Methane emission factors from natural gas distribution meters used for commercial and industrial applications. Error bars represent the 95th percentile confidence intervals around mean values These data are adapted from GTI's measurement campaign on industrial and commercial distribution meters.

the capacity and operating hours for compressors, emissions from pipeline blowdowns and other maintenance events, and emissions from transmission and storage facility leaks. For distribution, these data include the annual delivery volumes of natural gas and various sources of methane leaks. For the transmission and distribution stages, the GHGRP data are representative of 534 transmission compression stations, 48 underground natural gas storage facilities, 237 natural gas pipeline companies, and 170 natural gas distribution utilities. As an example of the types of data available through GHGRP, Figure 2 shows the energy consumption and corresponding uncertainty for transmission compressor facilities with two different technologies across six regions.

Previous versions of our life cycle model used only EPA's Greenhouse Gas Inventory (GHGI) to characterize emissions from distribution meters. For residential meters, the activity factor is 0.000206 meters per delivery of 1 kg of natural gas and the emission factor is 1.49 kg CH_4/meter-year (in this context, "meter" refers to the unit of equipment used to measure the flow of natural gas, not a unit of length). For commercial meters, the activity factor is 0.0000214 meters per delivery of 1 kg of natural gas and the emission factor is 9.73 kg CH_4/meter-year.[2,23] In this work, we are changing the parameters for commercial meters and adding a new category for industrial meters using data from the Gas Technology Institute (GTI). GTI conducted a measurement study for natural gas meters for industrial and commercial applications. The study comprised 337 measurements in natural gas distribution systems across the United States. GTI expressed the resulting emission factors as kilograms of methane emitted per meter-year (kg CH_4/meter-yr) and stratified them into six regions (Midwest, Northeast, Pacific, Rocky, Southeast, and Southwest). They also expressed emission factors in terms of leaker and population factors, where leaker factors are emissions from meters that are emitting methane and population factors are the aggregate of emitting and nonemitting meters. We use GTI's regional population emission factors for commercial and industrial meters for the six regions. Figure 3 shows the methane emission factors and corresponding uncertainty for industrial and commercial meters across six regions.

GTI's measurement study was an extensive campaign, but as indicated by the width of the mean confidence intervals in Figure 3, emission rates are highly variable, and far more than 337 measurements will be necessary to attain a representative sample. Wide variability and lack of representativeness are data quality challenges that are common in all emission studies for natural gas systems.

Production and Delivery Volumes. The U.S. produced 28.7 Tcf of natural gas in 2017. This natural gas was produced at onshore and offshore production sites.[1] Alaskan production (0.32 Tcf) is 91% of Alaskan consumption (0.35 Tcf); Alaska does not export natural gas to other states or Canada. We thus exclude Alaska from our balancing of state production and consumption. The remaining production locations comprise 16 states and Federal Offshore production in the Gulf of Mexico (GoM) and account for 28.4 Tcf of production. In 2017, the U.S. imported 2.8 Tcf of natural gas via pipeline from Canada; Alberta and British Columbia accounted for 72 and 28% of this natural gas, respectively.[32]

In 2017, 27.6 Tcf of natural gas was delivered by U.S. natural gas transmission pipelines. Natural gas deliveries comprise natural gas consumed by U.S. consumers and natural gas that is exported:

- In 2017, the U.S. consumed 30.1 Tcf of natural gas. This consumption volume comprised utility, industrial, commercial, residential, and vehicle fuel consumption in 50 states, the District of Columbia, and Federal offshore operations. To simplify our calculations, we used consumption data for states that cumulatively account for 99% of consumption and removed Alaskan consumption (for reasons explained above).[1]
- In 2017, the U.S. exported 2.41 Tcf of natural gas via pipeline (0.88 Tcf to Canada and 1.53 Tcf to Mexico). U.S. pipeline exports to Canada were at New York and Michigan. Niagara Falls, NY, was the highest-volume New York pipeline export location, and St. Clair, MI, was the highest-volume Michigan pipeline export location. U.S. pipeline exports to Mexico passed through Texas, Arizona, and California. Rio Grande, TX, was the highest-volume Texas pipeline export location, Douglas, AZ, was the highest-volume Arizona pipeline export location, and Ogilby, CA, was the highest-volume California pipeline export location.[33]
- In 2017, the U.S. exported 0.71 Tcf of natural gas via LNG ocean carriers. Most of this natural gas was exported from Sabine Pass, Louisiana.[34]

The natural gas transmission network delivers natural gas to large-scale users (power plants), but local distribution systems with low-pressure, narrow-diameter pipelines are necessary to deliver natural gas to small-scale consumers. In 2017, 54% of

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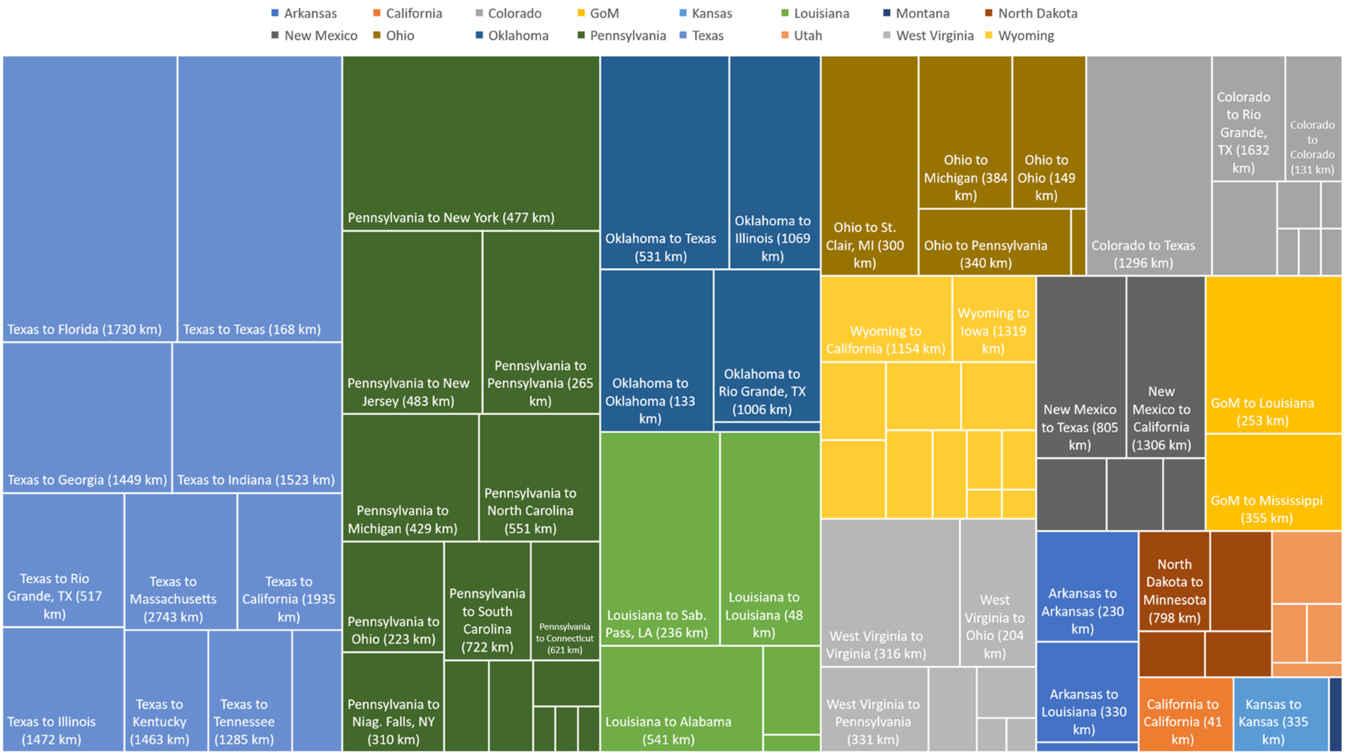

Figure 4. Relative transport volumes for state natural gas production and delivery pairings. The areas of the rectangles are proportional to total U.S. natural gas deliveries in 2017 and are color-coded to represent the origin state. The straight-line distance between state processing and state delivery centroids is shown in parentheses. Boxes that represent less than 200 Bcf/yr are not labeled. Tabular data are provided in the Supporting Information.

U.S. natural gas was delivered via local distribution, but the share of natural gas delivered by local distribution systems varies regionally. We used data compiled by the Homeland Infrastructure Foundation-Level Database (HIFLD) for natural gas local distribution service areas to calculate these regional distribution shares.[35] In increasing order, these shares are 24% for the Southwest, 36% for the Southeast, 60% for the Rocky Mountains, 61% for the Northeast, 80% for the Pacific, and 81% for the Midwest.

Pairing of Production and Delivery Markets. The markets to which a given producer sends natural gas are a function of total U.S. production volumes, the volume of natural gas demanded by consumers, and import and export flows. We do not know the exact pathways that natural gas travels between producers and consumers because the natural gas transmission network is an integrated system with thousands of nodes and bi-directional pipelines.[15] U.S. natural gas transmission is very complex, but we have developed a direct approach for pairing producers and consumers without engaging in a data- and computationally intensive characterization of exact pipeline flows. To estimate the transmission pathways, we employed an algorithm that links production and delivery locations by optimizing the shortest average transmission distance. This algorithm divides natural gas production volumes into 1000 parcels with Texas (the state with the most production) having 231 parcels and Montana (the state with the least production) having one production parcel. The algorithm also divides natural gas deliveries into 1000 parcels, with Texas (the state with the most deliveries) having 121 delivery parcels and Montana (the state with the least deliveries) having three delivery parcels. The parcel count of 1000 is large enough to apportion natural gas at a granular level of detail while remaining manageable within the structure of our algorithm. Based on the range of production rates across all producing states, using 1000 parcels incurs a 0.7% error (i.e., 0.7% of produced natural gas may be assigned to the wrong producing state). This error is small in comparison to the uncertainties in other modeling parameters (e.g., the volume-to-mass conversion factors for natural gas at different supply chain stages, the chemical compositions of raw and pipeline-quality natural gas, and the combustion effectiveness of flares at production and processing facilities) and the uncertainty caused by the wide variability in natural gas systems (e.g., equipment count variability, liquids unloading frequency and duration, and gas-to-oil ratios).

The algorithm iterates through a rotating list of producer states and links each producer parcel to the nearest available delivery parcel. After each iteration, the rotating list is updated by removing states that have exhausted their production parcel count. Montana has one production parcel, so it is only a part of the first rotation. Texas is the state with the most production, so it is a part of all 231 rotations. This rotating list ensures that no single state has a monopoly with respect to the nearest delivery points, allowing the algorithm to arrive at the optimal transmission distances for the entire U.S. transmission system. Due to transparent reporting by the California Public Utilities Commission,[36] we account for one special instance, the transport of natural gas from the Permian Basin in Texas and New Mexico to Southern California by the El Paso Natural Gas Pipeline Company, by initializing the algorithm with New Mexico and Texas each having 14 parcels dedicated to California. These 28 parcels from the Permian Basin to California represent 800 Bcf of natural gas (2.8% of the U.S. natural gas supply). The weighted average distance between production and consumption is 815 km, which includes a 9% distance increase that accounts for pipeline tortuosity. More details on our approach to pairing production and consumption

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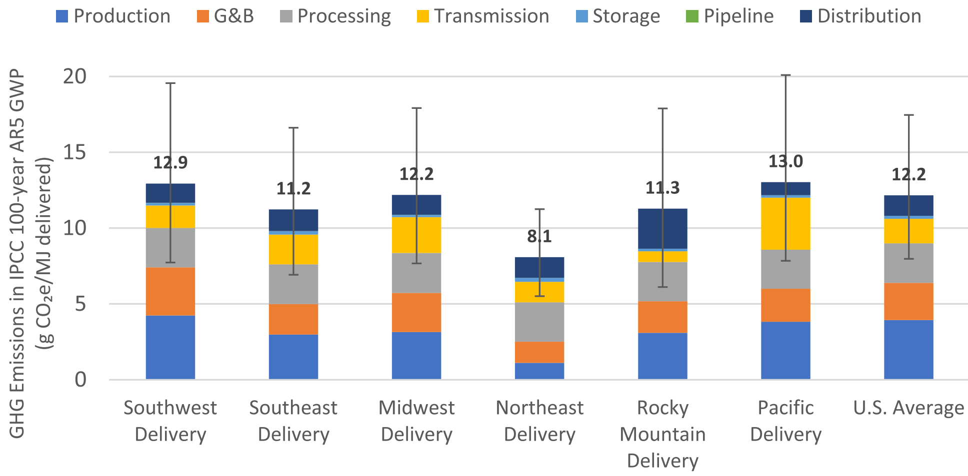

Figure 5. GHG emissions for six regional delivery scenarios from all production basins. The expected value for each scenario is represented by the height of each stacked bar. These expected values are shown in terms of 100-year GWP (using factors from IPCC's Fifth Assessment Report). The error bars for life cycle GHG emissions are representative of 95% mean confidence intervals. The U.S. average scenario is a delivery-weighted composite of the regional scenarios.

locations and calculating the resulting transport distances are provided in the Supporting Information. Figure 4 shows the output of the algorithm, with total production volumes of each state assigned to their delivery points.

Interstation Distances. The distance between compressor stations is based on the geographic coordinates of compressor stations for each pipeline company. We used data from the HIFLD characterization of natural gas compressor stations.[37] The HIFLD data is a compilation of data from Federal Energy Regulatory Commission (FERC) Form 2, Environmental Protection Agency (EPA) Envirofacts, and corporate websites. There are 1367 compressor stations and 78 pipeline companies in the natural gas transmission network. We segmented the data by pipeline company and identified the segments of the transmission network where compressor stations follow a direct pathway. This was necessary because the networks for some pipeline companies are highly branched with multiple intersections and require more information to determine the exact paths between compressor stations. There are 33 pipeline companies with direct paths, representing 320 compressor stations in total. For each of these companies, we calculated the interstation distances between all adjacent compressor stations. The average straight-line distances between a compressor station and its two nearest neighbors are 72.7 and 104 km, respectively. This work uses these two values to bound the average interstation distance, which is 88.2 km.

Tortuosity Factor. The straight-line distances shown in Figure 4 and the interstation distances discussed above are based on the great circle route between coordinates. In our model, we scale these distances by a tortuosity factor based on the straight-line and actual distances for five pipeline segments belonging to three pipeline companies (more details on these companies are provided in the Supporting Information). The tortuosity factors for these five segments range from 1.03 to 1.16. Data for actual pipeline distances are scarce. Due to this data limitation, this work models pipeline tortuosity using a uniform probability distribution function ranging from 1.03 to 1.16.

Regional Traverses. In instances where natural gas travels through multiple regions, we calculate a weighted profile of transmission and storage parameters using the fraction of transport through each region. We calculated these fractions by mapping the straight-line distance between the state processing and delivery centroids that compose each multiregion transmission scenario. For example, natural gas that is produced in Colorado and delivered to Arizona is transported in the Rocky Mountain and Southwest regions. The straight-line distance between the processing and delivery centroids for these states is 824 km, with 363 km (44%) in Colorado and 461 km (56%) in Arizona. The transmission profiles for the Rocky Mountain and Southwest regions are thus combined using a 44/56 split between the Rocky Mountain and Southwest transmission and storage parameters, respectively. (In this work, there are 49 instances of interstate transport scenarios where natural gas is transported in multiple regions.)

Transmission Station Throughput Factor. The throughputs for individual compressor stations are necessary to calculate the emission intensity (the emissions per unit of natural gas transported) for each compressor station. Such data are not available; however, data are available for installed horsepower and annual operating hours for individual compressor stations, allowing us to develop a factor that represents the relationship between compression energy and natural gas throughput. In 2017, the U.S. natural gas transmission system had 67,000 million HPh of compression energy[2] and transported 24.8 Tcf of natural gas.[38] Based on our above calculations for total and interstation distances, natural gas travels through, on average, 6.9 compressor stations between processing and delivery. This equates to an average compression energy intensity of 0.39 HPh per facility for every Mcf of natural gas throughput.

RESULTS

The average cradle-to-delivery GHG emissions for U.S. natural gas are 12.2 g CO_2e/MJ delivered, with a 95-percentile mean confidence interval ranging from 8.0 to 17.5 g CO_2e/MJ. The average cradle-to-delivery methane emission rate is 0.97%, with a 95-percentile mean confidence interval ranging from 0.61 to 1.43%. These results are a compilation of 101 unique pairings of technobasin and delivery regions. Figure 5 shows how these values vary for natural gas delivered to different regions. The Pacific region has the highest cradle to delivery expected value (13.0 g CO_2e/MJ) and the Northeast has the lowest expected

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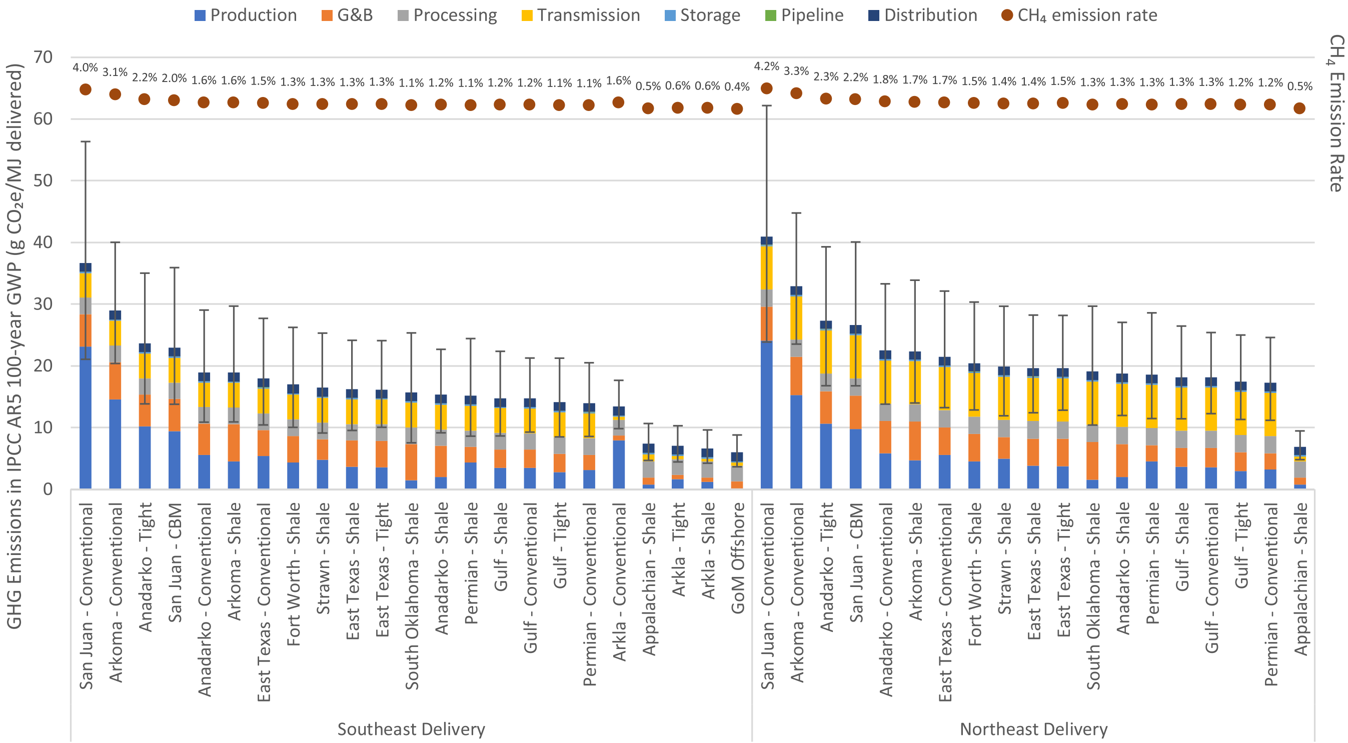

Figure 6. Life cycle GHG emissions for the technobasins that compose natural gas deliveries to the Southeast and Northeast. The expected value for each scenario is represented by the height of each stacked bar. These expected values are shown in terms of 100-year GWP (using factors from IPCC's Fifth Assessment Report). The error bars for life cycle GHG emissions are representative of 95% mean confidence intervals. Red dots represent CH_4 emission rates, which are calculated by dividing the mass of CH_4 emissions per mass of delivered natural gas.

value (8.1 g CO_2e/MJ). All scenarios have wide variability, and as such, the mean confidence intervals overlap across all regions.

The differences among regional delivery scenarios are a function of many variables, including the mix of technobasins that compose each scenario. The GHG emission profiles for the technobasins that supply the Southeast and Northeast delivery scenarios are shown in Figure 6. We have chosen to show detailed results for these two regions because they illustrate how the life cycle emissions from a given technobasin can differ between delivery locations. (Tabular data for all pairings between technobasins and delivery regions are provided in the Supporting Information). 24 technobasins compose Southeast deliveries, and 19 technobasins compose Northeast deliveries. For Southeast deliveries, no single technobasin contributes more than 14% to the total volume delivered; for Northeast deliveries, the Appalachian Shale technobasin accounts for 88% of natural gas delivery volumes. The average transmission distances for natural gas delivered to the Southeast and Northeast are 896 and 671 km, respectively. These supply parameters interact with the regionalized facility-level emission parameters that we derived from the GHGRP (as shown in Figure 2) to result in unique GHG emission profiles for every delivery scenario.

An interesting component of the Southeast delivery scenario is the Arkla scenarios, which comprise conventional, tight, and shale extraction technologies. These technobasins are close to consumers and do not send natural gas beyond the Southeast region. The transport requirements for the Arkla technobasins are low, which significantly reduces their life cycle GHG emissions. Further, the Arkla Conventional scenario demonstrates why CH_4 emission rate should not be the sole metric for GHG emission performance. The Arkla Conventional scenario has a life cycle CH_4 emission rate of 1.6%, which is higher than the average U.S. CH_4 emission rate of 0.97%, but its life cycle CO_2e is still lower than most scenarios. As evidenced by its high methane emission rate, there are emission mitigation opportunities for Arkla Conventional, but its proximity to consumers is an advantage that other scenarios do not have.

The San Juan Conventional scenarios demonstrate how transmission distance can change the life cycle emissions for a single technobasin. The San Juan Conventional technobasin contributes only 0.3% to total U.S natural gas deliveries but is in a remote area and, based on the constraints of our production-to-delivery algorithm, does not have an affinity for a single delivery region. When San Juan Conventional is delivered to the Southeast, the life cycle GHG emissions and CH_4 emission rate are 36.7 g CO_2e/MJ and 4.0%, respectively. When San Juan Conventional is delivered to the Northeast, the life cycle GHG emissions and CH_4 emission rate are 41.0 g CO_2e/MJ and 4.2%, respectively. The longer transport distance for delivery of San Juan Conventional to the Northeast compared to delivery to the Southeast (2983 vs 1722 km) increases its transmission emissions as well as all upstream emissions per unit of delivered natural gas. The functional unit of this work is a fixed quantity of delivered natural gas. The increased transmission energy requirements for the Northeast delivery scenario require more natural gas from upstream operations, thus incurring a marginal increase in upstream emissions.

DISCUSSION

A life cycle perspective is necessary for answering questions about specific natural gas production and consumption scenarios — scenarios that connect production through delivery. For example, companies that are compiling corporate GHG

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footprints can use the results from this work to represent the likely GHG emissions for natural gas used in a specific location. For example, Cheniere Energy, the leading U.S. exporter of liquefied natural gas (LNG), conducted an LCA that is representative of their supply chain and has used it to help meet their sustainability goals.[39] Other U.S. LNG exporters will likely follow suit with increasing pressure from European regulators to reduce the CH_4 emissions from natural gas imports.[40] Similarly, the level of detail and connectivity in this work is a useful tool for utility or industrial consumers who are searching for opportunities for reducing their upstream GHG emissions and can work with their suppliers to reduce upstream emissions. A life cycle perspective is also valuable for entities who are exploring investments in natural gas production basins and want to understand the GHG emissions downstream from their potential production activities.

A key implication for policy makers is that there is no single emission mitigation strategy that will be effective for every supply chain scenario. Production emissions account for most emissions from some scenarios, while midstream (processing and transmission) emissions account for most emissions from other scenarios. Reducing production emissions is a complex undertaking that requires more information on the different venting, fugitive, and combustion emission sources at production sites. Reducing transmission emissions is less complex than reducing production emissions because they are composed mostly of known emission sources from compressor operation. Collaboration between government and industry is necessary for developing policies that consider the differences between different supply chain scenarios.

Even after stratification into 102 specific production-to-delivery pathways, there is significant uncertainty in every scenario. The uncertainty in this work is driven by component-level variability. The types and counts of equipment, operating hours, and natural gas throughput at each point in the supply chain are highly variable, and there is no such thing as a "typical" production site, midstream station, or local distribution system. There are opportunities for improvement in every scenario. More data are required to identify top performers within each scenario so that they can be used as benchmarks for peer facilities.

Finally, methane emission rate should not be the sole metric used for evaluating the GHG emissions from natural gas systems. This is exemplified by the Arkla Conventional technobasin, which has high CH_4 emissions at production but a low life cycle CO_2e because of its low transmission requirements. The natural gas supply chain has many sources of combustion, venting, and fugitive emission sources, each with a unique mix of CO_2 and CH_4. Some scenarios have tradeoffs where there are low GHG emission intensities in one stage of the supply chain, but high GHG emissions at another stage of the supply chain. Using only one metric, like CH_4 emission rate, may highlight an emission reduction opportunity at one stage, but overlook an emission reduction opportunity at another stage.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.2c01205.

> Natural_Gas_Delivery_Pathways_GHG_Paper; development of regional transmission and distribution parameters; full inputs and outputs for the algorithm for production and consumption pairings; analysis of interstation distances and pipeline tortuosity, and stage-wise GHG emission results for all scenarios (PDF)

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Notes

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■ ABBREVIATIONS

AR5 fifth assessment report
CH_4 methane
CO_2 carbon dioxide
CO_2e carbon dioxide equivalents

EPA	environmental protection agency
FERC	federal energy regulatory commission
g	gram
GHG	greenhouse gas
GHGI	greenhouse gas inventory
GHGRP	greenhouse gas reporting program
GTI	gas technology institute
GWP	global warming potential
HIFLD	homeland infrastructure foundation-level database
HPh	horsepower hour
IPCC	intergovernmental panel on climate change
km	kilometer
LCA	life cycle assessment
LNG	liquefied natural gas
Mcf	thousand cubic feet
MJ	megajoule
N_2O	nitrous oxide
NETL	national energy technology laboratory
SI	supporting information
Tcf	trillion cubic feet
U.S.	United States

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